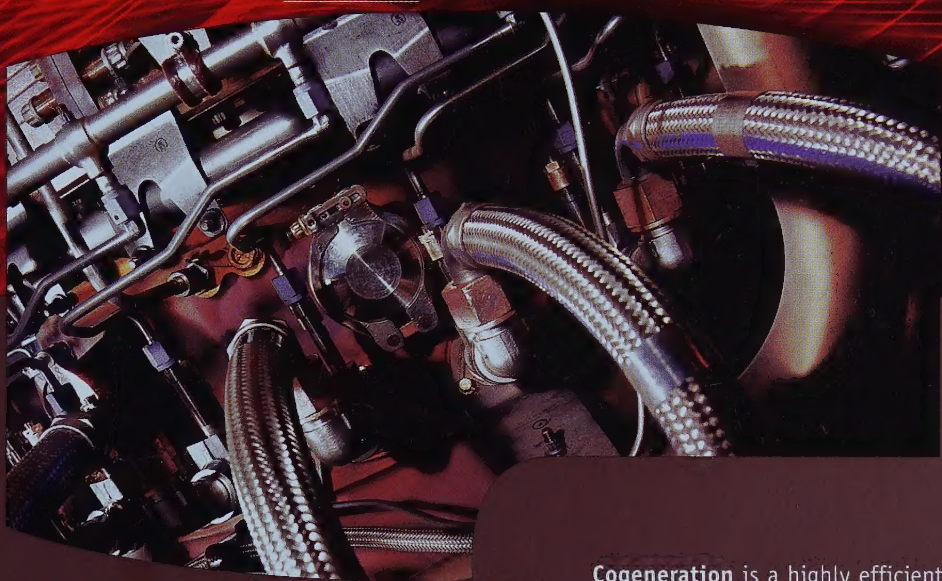
Northland Power Income Fund

Annual Report 2000



Cogeneration is a highly efficient means of simultaneously producing electric power and heat or steam — in a single thermodynamic process — from a single fuel source.

NORTHLAND POWER INCOME FUND

Northland Power Income Fund (the "Fund") is a trust that, directly and through its wholly owned subsidiary, Iroquois Falls Power Corp., owns a 110 MW cogeneration power plant located in Iroquois Falls, Ontario (the "Facility"). The Facility supplies electricity to Ontario Electricity Financial Corporation (as successor to Ontario Hydro) and steam to the neighbouring Abitibi-Consolidated Inc. pulp and paper mill. The electricity and steam are sold, and natural gas is purchased, under long-term contracts that reduce the Fund's exposure to unexpected price and volume fluctuations and provide predictable cash flow.

The Fund is administered and the Facility is managed by Iroquois Falls Power Management Inc., a wholly owned subsidiary of Northland Power Inc., which is a leading Canadian independent power company with extensive experience in all aspects of private power development and operational management.

As at March 8, 2001, the Fund had 30,823,443 trust units outstanding which trade on The Toronto Stock Exchange under the symbol NPI.UN. The units are qualified investments under the Canadian Income Tax Act for RRSPs and DPSPs and are not considered foreign property for such plans.

Glossary of Terms

Abitibi	Abitibi-Consolidated Inc.
DRIP	Northland Power Income Fund Distribution Reinvestment Plan
Facility	Plant located in Iroquois Falls, Ontario
Fund	Northland Power Income Fund
GJ	Gigajoules
IFPC	Iroquois Falls Power Corp.
kWh	Kilowatt hour
M	Million
MW	Megawatt
MWh	Megawatt hour
Manager	Iroquois Falls Power Management Inc.
OEFC	Ontario Electricity Financial Corporation

Highlights

Years ended December 31	2000	1999
Production		
Electricity (MWh)	**739,687**	778,307
Steam (000 lbs.)	**997,164**	868,431
Financial ($000)		
Sales	**61,576**	59,850
Net income	**18,965**	18,390
Funds from operations before working capital changes	**29,194**	28,724
Cash available for distribution	**23,116**	29,138
Distributions declared to unitholders ($000)	**28,974**	28,666
Distributions per unit	**$0.94**	$0.93

Distributions at $0.94 (98.4 per cent tax-deferred) were above the forecast in last year's annual report and the $0.93 per unit achieved in 1999.

Plant employees continued their exemplary safety record; there have been no lost-time injuries since plant start-up in 1996.

Sales revenue in 2000 was up 3 per cent from the prior year, as a result of higher market prices on gas resold to mitigate TransCanada PipeLines Limited costs.

The plant continues to meet all Ministry of Environment requirements and standards.

Cogeneration is a synergy — a unity — where the whole is greater than the sum of its parts. It is a creative conjunction of forward-thinking concepts, engineering prowess and modern gas turbine and electricity generation technologies. Developed by professional designers, cogeneration is safe, delivers high-efficiency output, and minimizes the impact of both process and by products on the natural environment.

Letter to Unitholders

The year 2000 was very successful for the Northland Power Income Fund. Distributions amounted to $0.94 per unit or $29 million, which was higher than both our forecast going into the year and 1999's results.

Revenues and net income both exceeded last year, largely as a result of higher prices achieved for gas resold to mitigate fixed transportation costs on the TransCanada PipeLines Limited system. Electricity revenue was lower than 1999 due to lower sales to the Ontario Interim Market and more unpaid curtailment, while steam sales to Abitibi were slightly higher than 1999 sales.

Our approach of having 100 per cent of the Facility's gas requirements supplied under long-term contracts was substantiated in 2000 as the market price of natural gas increased significantly over the course of the year. Distributions are protected from the impact of higher natural gas market prices by the Fund's gas supply agreements.

Trust Unit Performance

The Fund's total return in 2000 (distributions plus increase in unit price) was 23 per cent. As shown in the graph on page 5, the Fund's return for 2000 compared favourably to the performance of other power income funds and the TSE 300 Index. For original unitholders, the Fund has met or exceeded forecast distributions each quarter since inception except for the third quarter of 1998, which was affected by a strike at Abitibi's mill.

Electricity Industry Deregulation

The competitive electricity market in Ontario did not open in November 2000 as had been announced because a number of the market participants had not completed their preparations; a new date has not yet been established. Discussions between the Manager and Ontario Electricity Financial Corporation regarding modifications in the Fund's long-term power purchase agreement as part of the transition to a competitive market are continuing with a mutual goal of achieving agreement prior to market opening.

To facilitate the Fund's ability to participate in the competitive market, the Manager is seeking unitholder approval for changes to the management agreement. The Manager is proposing to bear the on-going costs associated with complying with the technical and operational requirements of the new market rules (rather than the Fund) and to absorb any one-time costs in excess of $250,000 (up to which amount the Fund is responsible), in return for a share of any future benefits achieved by the Fund. Details of the proposal are provided in the management information circular mailed to unitholders with this annual report. The Manager continues to believe that participation in the competitive marketplace will offer the Fund and its unitholders significant opportunities and benefits.

Distribution Reinvestment Plan

To provide further flexibility and value for unitholders, the Fund is implementing a distribution reinvestment plan ("DRIP") that all Canadian unitholders are eligible to join. The DRIP allows eligible holders of trust units to conveniently purchase additional trust units by reinvesting their cash distributions. Please refer to the management information circular for further details.

Acquisitions

To achieve diversification of the Fund, the Manager continued to investigate acquisition opportunities during the year; however, none met the trust indenture requirements of preserving the current risk profile of the Fund while increasing distributions. The recent strengthening in the Fund's unit price should help to facilitate accretive acquisitions.

2001 Forecast

For 2001, the Manager is projecting distributions of $0.94 per unit, of which approximately 80 per cent is expected to be tax-deferred and 20 per cent taxable to unitholders. Monthly distributions are forecast to be $0.075 per unit with the December distribution being $0.115.

The Iroquois Falls plant continues to maintain its outstanding safety record. Since the plant started up in September 1996, there have been no lost-time injuries. I would like to thank the employees of the plant for this exceptional achievement and their hard work at maintaining the excellent operations. Unitholders can anticipate another year of strong performance and consistent cash distributions from the Northland Power Income Fund.

On behalf of the administrator of the Fund and the Manager of the Iroquois Falls plant,

James C. Temerty,
President
Iroquois Falls Power Management Inc.
March 8, 2001

Distributions

†nine months

Cogeneration accounts for well over half of all new power plant capacity built in North America in the last decade. The inherent efficiencies of this technology are largely responsible for the dramatic decline of nuclear and hydraulic power plant construction that occurred in the 1980s.

Distributions in 2000 were the highest since the inception of the Fund. The Fund changed its distribution policy, moving from quarterly to monthly levelized distributions. The Fund continues to be a stable income source for unitholders.

Report on Operations

For the fiscal year ended December 31, 2000, the Fund distributed $0.94 per unit to unitholders, which was 98.4 per cent tax-deferred. Distributions were higher than the forecast contained in last year's annual report, and exceeded the 1999 distribution of $0.93 per unit. In August, following unitholder approval, the Fund changed its distribution policy, moving from quarterly to monthly levelized distributions.

Sales revenue in 2000 of $61,576 thousand was 3 per cent higher than 1999 as a result of higher revenue from resale of natural gas. The Fund resells gas to mitigate the fixed transportation costs it pays to TransCanada PipeLines Limited; revenue from gas sales of $6,502 thousand was 73 per cent higher than the prior year largely because of higher prices. Electricity revenue of $50,570 thousand was 2 per cent lower than 1999. Electricity production declined by 5 per cent as a result of lower sales to the Ontario Interim Market operated by Ontario Power Generation Inc. and curtailment not being cancelled by Ontario Power Generation Inc.; however, higher-priced sales under the power purchase agreement represented a larger portion of revenue, which contributed to the average selling price of electricity increasing by 3 per cent from 1999. Steam sale revenue from Abitibi at $4,504 thousand was up 3 per cent from the prior year.

The cost of sales at $25,584 thousand was 2 per cent higher than 1999. The cost of natural gas consumed at the Facility was unchanged as higher prices for gas and gas transportation were offset by a reduction in gas used due to lower electricity production, while the cost of natural gas resold increased as a result of higher prices.

Total plant and other costs including interest but excluding income taxes amounted to $17,110 thousand; a 5 per cent increase over the prior year. Higher plant operating costs were associated with normal maintenance of plant equipment that is now four years old, while general and administrative costs were higher as a result of due diligence costs relating to potential acquisitions and gas management fees paid to the Manager. The higher gas management fees are a reflection of the higher gross profit realized from natural gas sales. Other cost categories were largely in line with the prior year.

Net income of $18,965 thousand was 3 per cent higher than last year due to the higher revenue, while funds from operations were up by $470 thousand. Cash available for distribution was $6,022 thousand lower than 1999 due to changes in working capital as a result of timing that, while significant in magnitude, are insignificant in impact. Ontario Electricity Financial Corporation ("OEFC") is obligated to pay for electricity 21 business days after month-end; because of the timing of weekends and holidays in 2000 this meant that the $5,201 thousand payment for November's electricity sales was received on January 3, 2001, rather than before the end of December. This accounts for most of the working capital change; the balance is largely accounted for by an increase in natural gas inventory of $693 thousand because of a change in the Manager's strategy from last year in how it meets the Fund's winter peak needs for gas.

There were several significant changes on the Fund's balance sheet at December 31, 2000, compared to the previous year. Accounts receivable were up due to the timing of November's payment from OEFC, gas inventory levels increased, and the commencement of monthly distributions to unitholders in 2000 decreased the amount payable to unitholders at year-end. These factors reduced the amount of year-end cash and contributed to the Fund having to borrow under its bank line for a few days over year-end. Other than this short-term borrowing, the Fund continued to remain debt-free.

Several acquisition opportunities were investigated in 2000 with the goal of diversifying the Fund. However, none met the trust indenture requirements of preserving the current risk profile of the Fund while increasing distributions.

Protection of Gas Costs

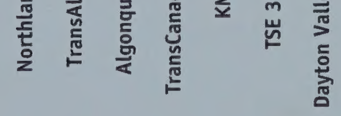
The Manager's approach of having 100 per cent of the Facility's gas requirements supplied under long-term contracts was substantiated in 2000 as the market price of natural gas at the end of December 2000 was almost five times higher than at the beginning of the year.

The combined return in 2000 compared favourably with other income funds and the TSE 300 Index. Except for 1999, when non-technology sectors were out of favour, unitholders have received double-digit returns every year since the Fund's inception.

The Facility uses major equipment built by world industry leaders to generate its power and steam requirements with a high level of reliability. The Facility's operating life is expected to extend well beyond the 25-year term of the power purchase agreement.

Cogeneration systems typically include a gas-fired turbine, essentially a jet engine, that drives an electrical generator. Heat exchangers recover heat from the engine hot exhaust to produce hot water or steam. Cogeneration produces a given amount of electric power and process heat with 10 per cent to 50 per cent less fuel than it would take to produce the electricity and process heat separately.

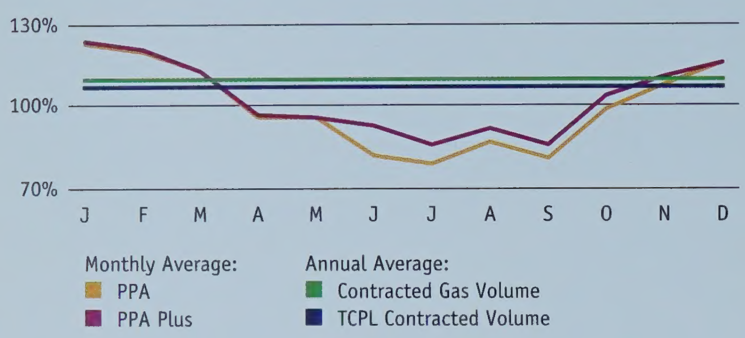
Comparative Returns



Data courtesy of CIBC World Markets Inc.

The graph below illustrates that the Fund has contracted long-term for sufficient gas and gas transportation to meet its entire fuel needs. The "PPA" line represents the monthly average quantity of gas required by the Facility to produce the quantity of electricity that OEFC is obligated to purchase under the terms of the long-term power purchase agreement; the "PPA Plus" line is similar but also includes gas for electricity sales to the Ontario Interim Market. The 100 per cent level of the graph is the annual average "PPA" gas consumption. The "Contracted Gas Volume" and "TCPL Contracted Volume" lines represent the total gas supply under the long-term contracts and the contracted TransCanada PipeLines Limited transportation capacity available, which are equivalent to approximately 109 per cent and 107 per cent respectively of average annual "PPA" gas consumption. This extra volume, combined with summer purchases for inventory, is required to allow the Fund to meet the Facility's peak winter gas needs (as shown by the "PPA" line), as well as to supply electricity beyond the power purchase agreement volumes. In summer, when electricity production is lower, the Fund generally resells gas at market prices to mitigate the cost of unused TransCanada PipeLines Limited capacity; certain of the gas contracts provide limited re-sale rights for that purpose.

Natural Gas Supply and Transportation Contracts



The long-term gas contracts provide protection to the Fund's distributions against fluctuations in the market price for natural gas.

Industry Update

As described in last year's annual report, Ontario Hydro was restructured on April 1, 1999. The legal successor to Ontario Hydro's obligations under the Fund's long-term power purchase agreement is OEFC, a Crown agency whose obligations, including those under the power purchase agreement, are guaranteed by the province of Ontario.

As part of the transition to a competitive market, discussions with OEFC regarding modifications in the long-term power purchase agreement are continuing. The significant transitional issues are the replacement of the Ontario Hydro price indices that are the basis for selling price changes under the power purchase agreement, OEFC's claims to exclusivity (which the Manager disputes), and agreement on responsibility for certain one-time costs associated with the opening of the competitive market. OEFC and the Manager are mutually committed to completing negotiations prior to the opening of the competitive market, the date for which has not yet been established.

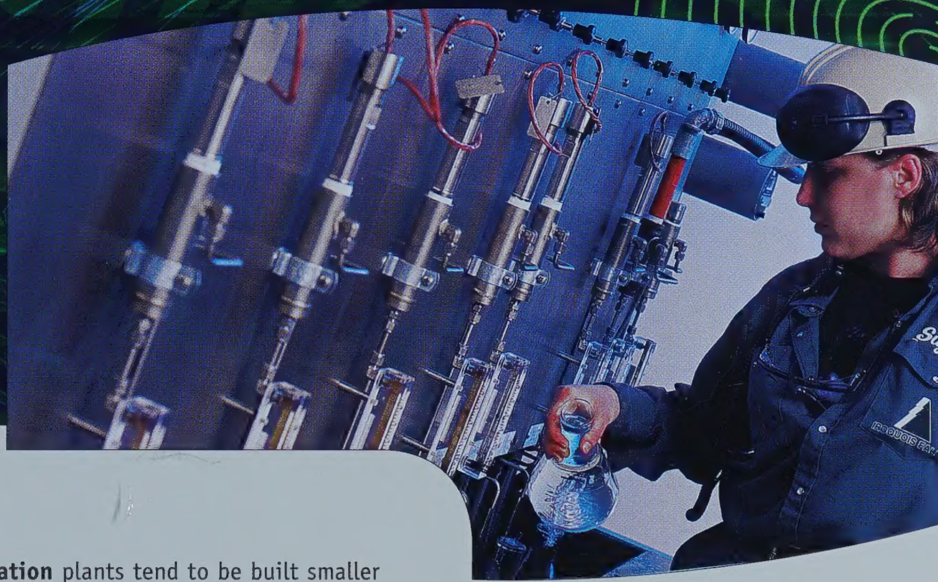
The Manager believes that active participation in the open market will provide the Fund and its unitholders with significant benefits and opportunities. Active management of the power purchase agreement in cooperation with OEFC is expected to provide profit upside, potentially with lower electricity production. Also, the Fund will be well positioned to use its surplus capacity to sell electricity to the market subject to resolving OEFC's exclusivity claim.

To facilitate the Fund's ability to participate in the competitive market, the Manager is seeking unitholder approval for changes to the management agreement. The Manager is proposing to bear the on-going costs associated with complying with the technical and operational requirements of the new market rules (rather than the Fund) and to absorb any one-time costs in excess of $250,000 (up to which amount the Fund is responsible), in return for a share of any future benefits achieved by the Fund. Details of the proposal are provided in the management information circular mailed to unitholders with this annual report.

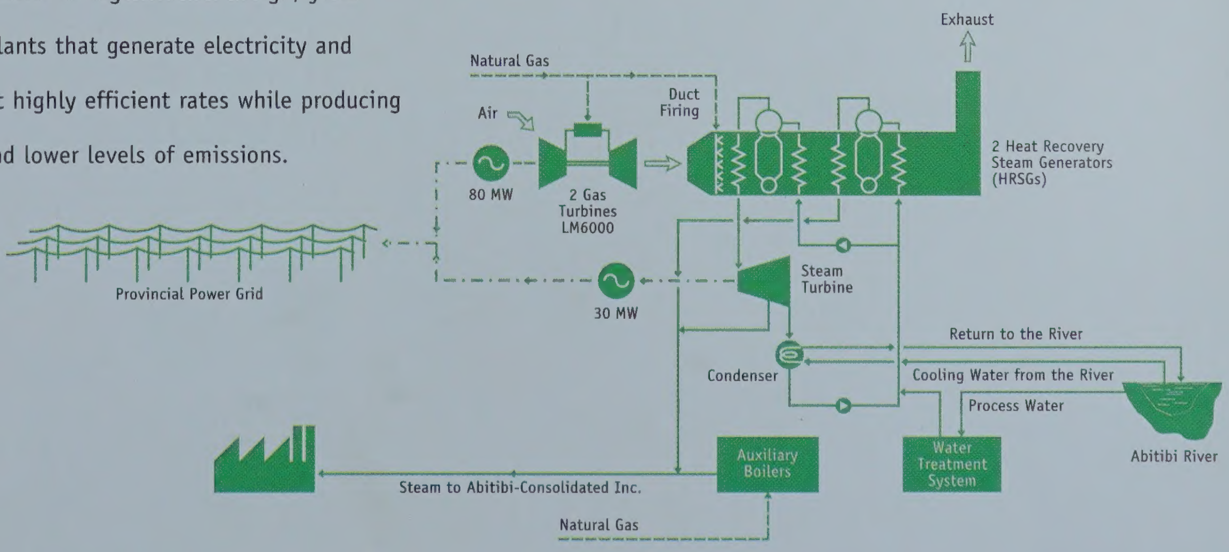
2001 Forecast

Distributions for 2001 are forecast at $0.94 per unit, of which approximately 80 per cent is expected to be non-taxable (tax-deferred) and the remaining 20 per cent is taxable. The forecasted $0.94 per unit distribution is in line with the distributions in 2000. Monthly distributions are forecast to be $0.075 per unit with a December distribution of $0.115 per unit to bring total distributions for the year up to the forecasted level.

The Facility is operated by engineers and operators who are required to meet legislated educational and experience standards. A fourth-class stationary engineer is required to successfully complete post-high school courses in several technical subjects and obtain at least 500 hundred hours of practical experience. Another 18 exams and approximately eight years of experience are needed to obtain the first-class designation. The Facility has had minimal employee turnover since inception.



Cogeneration plants tend to be built smaller and closer to populated areas, which results in higher levels of public awareness and higher environmental expectations. The use of clean-burning natural gas, coupled with the efficiencies inherent in cogeneration design, yield power plants that generate electricity and steam at highly efficient rates while producing fewer and lower levels of emissions.

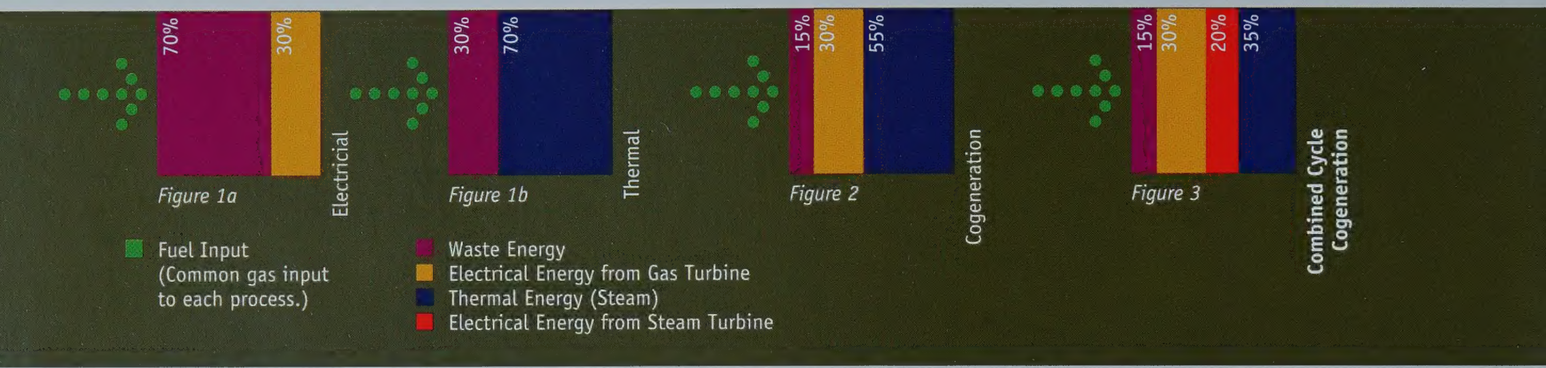


Why Cogeneration?

Cogeneration is the simultaneous production of electric and thermal energy, such as steam or heat, from one fuel source, such as natural gas. The steam produced is normally supplied to a nearby industrial or commercial facility, such as the Abitibi mill at Iroquois Falls, which would otherwise consume fuel to produce steam. Cogeneration provides greater efficiency than conventional generation methods to facilities that require continuous thermal and electric power.

Combined Cycle Cogeneration

A combined cycle cogeneration system, like that at the Iroquois Falls Facility, takes cogeneration a step further; it has all the benefits of cogeneration while producing relatively more electricity, a higher value product, and less heat. This is achieved by using steam produced by cogeneration and directing it to a steam turbine, which powers a generator to produce more electricity, after which the steam is used for heating or other



Figures 1a and *1b* depict conventional arrangements where electrical and thermal energy are generated separately. In arrangements where electricity is generated by itself in conventional power plants, approximately 30 per cent to 35 per cent of the fuel's energy content is converted into useful energy output in the form of electricity. The remainder is wasted as unused heat.

By producing electricity and steam simultaneously, cogeneration uses a higher proportion of the fuel's energy content. Depending on the degree of steam and/or useful heat utilization, 55 per cent to 85 per cent of the fuel's energy content is converted into useful energy output. *Figure 2* depicts the efficiency benefit of the cogeneration process.

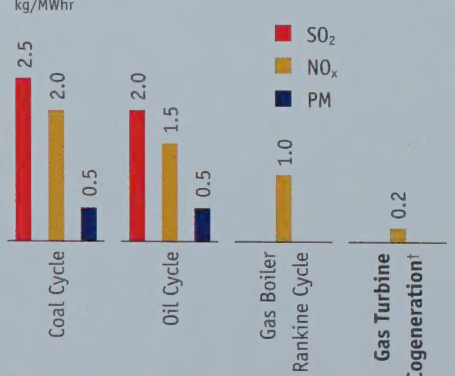
This increased efficiency translates into lower emissions of pollutants than generating electricity and heat separately. By using heat that would otherwise be discarded, cogeneration reduces the emissions from producing electricity and heat since less fuel is consumed.

processes, such as at the Abitibi paper mill. Like simple cogeneration, 55 per cent to 85 per cent of the fuel energy is used, but electrical energy outputs of 50 per cent to 55 per cent can be achieved compared to the 30 per cent to 35 per cent electrical efficiencies of simple cogeneration (as depicted in *Figure 2*). *Figure 3* depicts the increased production of electricity using combined cycle cogeneration.

By using natural gas to fuel the Facility's two General Electric gas turbine generator sets, the Iroquois Falls Facility is using the cleanest-burning fossil fuel. Natural gas combustion results in virtually no atmospheric emissions of sulfur dioxide (SO_2) or small particulate matter (PM), and far lower emissions of carbon monoxide (CO), nitrogen oxides (NO_X), and greenhouse gases such as reactive hydrocarbons and carbon dioxide (CO_2), than the combustion of other fossil fuels.

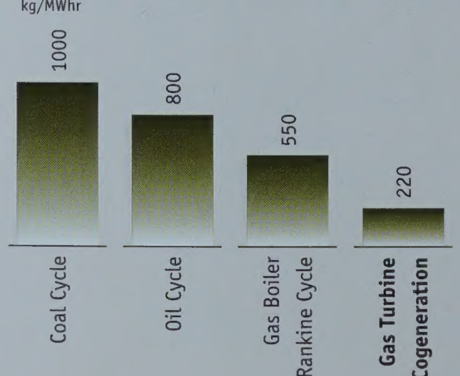
For more information on cogeneration and the Fund visit the Fund's web site at NPIFund.com.

Comparison of Air Pollution Emissions from Various New Energy Generating Plants
kg/MWhr



†With abatement technology

Comparison of CO_2 Emissions from Various Power Generation Plants (Greenhouse Gases)
kg/MWhr



Source: Environment Canada

Northland Power Income Fund (the "Fund") is a trust that was established in April 1997 to acquire the Iroquois Falls cogeneration facility (the "Facility"). The Fund's business activities are conducted through its wholly owned subsidiary, Iroquois Falls Power Corp. ("IFPC"), which sells electricity to Ontario Electricity Financial Corporation ("OEFC") and Ontario Power Generation Inc., and steam to a neighbouring pulp and paper mill owned by Abitibi-Consolidated Inc. ("Abitibi"), primarily under long-term contracts.

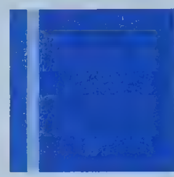
This Management's Discussion and Analysis compares the Fund's 2000 financial results to the results for 1999.

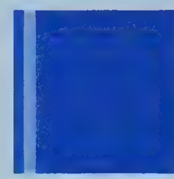
The Fund's 2000 distributions to unitholders of $28,974 thousand, or $0.94 per unit, were up from 1999 distributions of $0.93 per unit primarily because gross profit was higher by 3.8%.

Revenue and Cost of Sales In thousand of dollars except as indicated otherwise	2000	1999
Electricity		
Production (MWh)	**739,687**	778,307
Average price ($/kWh)	**0.0684**	0.0664
Sales	**50,570**	51,704
Steam		
Production (000 lbs.)	**997,164**	868,431
Average price ($/000 lbs.)	**4.52**	5.04
Sales	**4,504**	4,381
Natural Gas	**6,502**	3,765
Total Sales	**$61,576**	$59,850
Cost of Electricity and Steam Sales: Natural Gas		
Volume consumed (000 GJ)	**6,935**	7,145
Average price of gas consumed ($/GJ)	**3.19**	3.08
Cost of gas consumed	**22,119**	22,048
Cost of Natural Gas Purchased for Resale	**3,465**	3,118
Total Cost of Sales	**$25,584**	$25,166

Facility electricity revenue in 2000 was $1,134 thousand lower than the 1999 level as a 5.0% decrease in the volume sold was only partly offset by a higher average selling price. In 2000, OEFC fully exercised its limited right to curtail off-peak electricity purchases during the summer months, which resulted in 14,000 MWh of lower sales volume under the long-term power purchase agreement when compared to 1999. Successful bids to the Ontario Interim Market operated by Ontario Power Generation Inc. were made in 2000 but below the 1999 level by 25,000 MWh. The 2000 average electricity selling price increased by 3.0% because, while the average selling price under the power purchase agreement increased by only 1.6%, sales under the power purchase agreement (paid at a higher price than sales to the Ontario Interim Market) represented a greater proportion of electricity sales revenue than in 1999.

Revenue	2000		1999	
Electricity sales	**50,570**	**82.1%**	51,704	86.4%
Steam sales	**4,504**	**7.3%**	4,381	7.3%
Natural gas sales	**6,502**	**10.6%**	3,765	6.3%
Totals (thousands of dollars)	**$61,576**		$59,850	





Steam revenue was 2.8% higher in 2000. Steam volume was up by 14.8% as Abitibi reduced its own steam production compared to 1999. The variance between steam volume and steam revenue results partly because $260 thousand of revenue has been deferred until March 2001 when the winter-take-or-pay reconciliation is completed. Also, the contractual payment associated with Abitibi's operation of its own wood-fired boiler, which is independent of volume, was averaged over the larger volume of steam exported in 2000.

Revenue of $6,502 thousand was received for natural gas that was resold to mitigate the cost of unused capacity under the transportation contract with TransCanada PipeLines Limited during lower production summer months and plant shutdowns. Natural gas sales in 2000 were $2,737 thousand above the 1999 level due largely to favourable market prices.

The cost of natural gas consumed at $22,119 thousand was in line with the prior year. The volume of gas consumed was 2.9% lower because the 5.0% decrease in electricity production was partially offset by 14.8% higher steam volume. The price of gas consumed was up from 1999 because of contractual gas price increases of 4% and a 9.3% increase in the TransCanada PipeLines Limited tariff; gas sales helped mitigate transportation costs, resulting in an increase in the average cost of gas consumed of 3.2%. The cost of gas purchased for resale totalled $3,465 thousand, $347 thousand higher than 1999, primarily because of the increase in contractual prices and a higher level of TransCanada PipeLines Limited mitigation.

Expenses Including Interest In thousands of dollars except as indicated otherwise	2000	1999
Plant operating costs	**$5,967**	$5,762
Amortization	**9,240**	9,242
Management & administration costs, including capital tax	**2,027**	1,473
Interest and bank fees	**135**	112
Interest income	**(259)**	(316)
Total expenses including interest	**$17,110**	$16,273

Total expenses including interest at $17,110 thousand were $837 thousand higher than 1999 due to increased plant operating costs and management and administration costs. Plant operating expenses were up $205 thousand from 1999 (3.6%) due to additional normal maintenance of plant equipment that is now 4 years old. Management and administration costs were $554 thousand ahead of last year because of incentive fees to the Manager related to gas management savings (approximately $300,000) and the cost of investigating potential acquisitions ($250,000). Interest income was $57 thousand lower than in 1999 due largely to the declining balance in the prepaid General Electric maintenance fees account.

Net income in 2000 exceeded the 1999 level by $575 thousand because of higher gross profit.

Distributions to Unitholders
In thousands of dollars except as indicated otherwise

	2000	1999
Funds from Operations Before Working Capital Changes	**$29,194**	$28,724
Net change in non-cash working capital	**(6,059)**	546
Cash Provided by Operating Activities	**$23,135**	$29,270
Less: net capital expenditures	**63**	(57)
Less: funds set aside for future maintenance costs	**(82)**	(75)
Cash Available for Distribution	**$23,116**	$29,138
Distributions Declared to Unitholders	**$28,974**	$28,666
Number of trust units (thousands of units)	**30,823**	30,823
Per Unit ($/unit)		
Funds from operations before working capital changes	**$0.95**	$0.93
Cash available for distribution	**$0.75**	$0.95
Distributions declared to unitholders	**$0.94**	$0.93

Funds from operations before changes in working capital of $29,194 thousand exceeded the 1999 level by $470 thousand; however, cash available for distribution was $6,022 thousand lower than in 1999 due to changes in working capital. OEFC is obligated to pay for electricity 21 business days after month-end; because of the timing of weekends and holidays in 2000, the $5,201 thousand payment for November's electricity sales was received on January 3, 2001, rather than before the end of December. The balance of the change in working capital is largely accounted for by an increase in natural gas inventory of $693 thousand because of a change in the Fund's strategy from last year in how it meets its winter peak needs for gas.

Distributions declared to unitholders for 2000 totalled $28,974 thousand or $0.94 per unit, compared to $28,666 thousand and $0.93 per unit in 1999. The increases were due primarily to the additional revenue resulting from the higher sales.

Tax Treatment of Distributions

Distributions to unitholders in 2000 were 98.4% tax-deferred. The tax deferral arises as the Fund's capital cost allowance and expenses significantly reduce the Fund's income that would otherwise be taxable. The tax-deferred portion of distributions represents a return of capital for Canadian income tax purposes, and reduces the adjusted cost base of the units.

Generally, a trust unit is considered to be capital property. The actual or deemed disposition of a unit will give rise to a capital gain (or loss) equal to the amount by which the proceeds of disposition of a unit are greater (or less) than the adjusted cost base of the unit and any associated selling expenses.

Distributions in 2001 are expected to be approximately 80% tax-deferred and 20% taxable to unitholders.

Seasonality of Distributions

The Fund's cash available for distributions is seasonal as OEFC has contracted for more electricity and pays a higher price in winter than in summer. In addition, steam sales to Abitibi are higher in winter. Distributions to unitholders in prior years reflected this seasonality. The Manager received approval at last year's annual general meeting of unitholders for a trust indenture change that permits monthly distributions (rather than quarterly) and the levelization of distributions through the year. The change to monthly distributions commenced in August 2000.

Liquidity and Capital Resources

The Fund had no long-term debt at December 31, 2000. The Fund's subsidiary, IFPC, has a line of credit of $12.5 million consisting of a $7.5 million revolving letter of credit facility used in meeting obligations under the TransCanada PipeLines Limited contract and a $5 million revolving operating line of credit to be used for general corporate purposes. As of December 31, 2000, a letter of credit for $5.9 million was outstanding and short-term borrowings under the operating line of credit were $2,105 thousand. It was necessary to borrow under the bank line for a few days over year-end due primarily to the timing of the receipt of payment from OEFC for November's electricity sales.

Distribution and Funding Policy

It is the Fund's policy to distribute 100% of estimated cash flow to unitholders after providing for required capital expenditures and any increases in working capital, which are not expected to be material. It is anticipated that material capital expenditures, if any, that enhance cash flow and distributions to unitholders will be financed using the operating line of credit which would then be repaid from incremental cash flow. Any permitted acquisitions and plant expansions would be undertaken only if approved by the IFPC Board of Directors and funded by a combination of borrowings and the issuance of additional units.

Commitments

The Facility generates electricity and sells it to OEFC under a power purchase agreement expiring in 2021. The power purchase agreement obligates OEFC to purchase quantities of electricity ranging from a monthly average of 77 MW in the summer months to 96 MW in the winter (the yearly average is approximately 85 MW). OEFC is required to purchase additional electricity after December 31, 2001, for the remaining term of the steam sales agreement if Abitibi permanently reduces or eliminates, or predicts an extended reduction in, its need for steam for a period of one year or more.

Steam is supplied by the Facility to the neighbouring Abitibi pulp and paper mill under a steam sales agreement that expires in 2016. The agreement obligates Abitibi to pay for a minimum quantity of steam for a six-year period ending May, 2003, under a take-or-pay clause that provides Abitibi with relief for a six-month period should a force majeure event occur.

The Facility is fueled by natural gas provided by PanCanadian Petroleum Limited, Shell Canada Ltd., and Encal Energy Ltd. pursuant to gas supply contracts that end at various times between 2015 and 2017. The gas is transported through pipelines owned by TransCanada PipeLines Limited and Union Gas Limited from western Canada to the plant site under firm service agreements that run to 2016.

The maintenance of the two LM 6000 gas turbines is contracted to General Electric Canada Inc. under a maintenance agreement that was extended in 2000 and now expires in 2008 and is further renewable at IFPC's option under similar terms.

The unionized employees at the Iroquois Falls Facility work under a collective agreement that expires June 30, 2002.

The Facility is operated by Iroquois Falls Power Management Inc. (the "Manager"), a wholly owned subsidiary of Northland Power Inc., under a management agreement expiring in 2021. The Fund is administered by the Manager under the administration agreement.

Risks and Uncertainties

The amount distributed by the Fund to unitholders is dependent upon the parties to the Fund's long-term contracts continuing to fulfill their contractual obligations. In particular, as electricity sales represent 80% to 90% of the Fund's revenues, failure of OEFC to meet its contractual obligations would have an adverse affect on distributions.

On April 1, 1999, Ontario Hydro was reorganized into five successor companies. OEFC, one of the successor companies, holds all rights, obligations and liabilities related to the power purchase agreement. Both the Ontario government and OEFC are committed to continuing to honour the Facility's long-term power purchase agreement notwithstanding the restructuring of Ontario Hydro.

Increases in the selling price of electricity under the power purchase agreement are indexed to Ontario Hydro selling price indices (the Direct Customer Rate ("DCR") and Average Customer Rate ("ACR")). The Fund's revenues from electricity sales under the power purchase agreement are directly tied to changes in the DCR and ACR, although approximately 23% of such electricity revenue is subject to 3.3% minimum escalation. Discussions with OEFC have commenced to establish mutually satisfactory replacements for the DCR and the ACR indices. The impact that such replacements may have on future electricity price changes under the power purchase agreement is not yet determinable.

The Fund has generated revenue from electricity sales to the Ontario Interim Market operated by Ontario Power Generation Inc. and, prior to Ontario Power Generation Inc.'s formation, Ontario Hydro. Although the Manager considers otherwise, it is the position of OEFC and Ontario Power Generation Inc. that the Fund is required to sell any electricity it generates in excess of the quantities under the power purchase agreement exclusively to OEFC or Ontario Power Generation Inc.. The Ontario Interim Market is expected to be discontinued once the competitive market opens. The Fund may not be permitted to sell electricity outside the terms of the power purchase agreement to the competitive market unless this matter is resolved with OEFC. As a result of the opening of the competitive market, some additional costs, such as generator licensing fees, could arise.

Participation in the de-regulated electricity market may expose the Fund to additional risks. The Manager will establish procedures to minimize such exposure.

Abitibi's demand for steam is determined by operations at its Iroquois Falls pulp and paper mill, including the level of its own steam production. The Facility is obliged to respond to fluctuations in Abitibi steam needs. Demand for steam has an impact on gas consumption, and unexpectedly large short-term fluctuations in steam demand increase gas consumption without a proportionate increase in steam revenue.

Contracted gas prices generally escalate with Ontario Hydro's DCR subject to a 4% minimum annual increase. The gas contracts provide for price adjustments (subject to predefined ceilings) approximately every five years for which 50% of any resulting incremental costs are borne by OEFC. Alternatively, the periodic gas price adjusters could decrease contracted gas prices relative to electricity prices; OEFC shares in approximately 40% of any such savings. The impact of replacing the DCR as escalator is not yet determinable. Failure by the Facility's natural gas suppliers to provide gas under the long-term contracts could result in higher gas prices.

Any failure by TransCanada PipeLines Limited or Union Gas Limited to deliver natural gas to the Facility will have an adverse impact on cash distributions.

The Fund is subject to operational risks that could have an adverse affect on cash distributions. These risks are partially mitigated by the proven nature of the technology and design of the Facility, the availability of critical spares on site, the gas turbine maintenance agreement with General Electric Canada Inc., and participation in the General Electric Canada Inc. gas turbine lease pool which guarantees the availability of replacement gas turbines on short notice. The Fund has business interruption insurance to help mitigate the impact on distributions of other adverse occurrences that are insured.

The Facility operations are subject to numerous environmental laws and regulations. The Facility has an environmental monitoring and reporting system in place. Changes in environmental laws and regulations could possibly result in additional expenses, capital expenditures, and restrictions in the Facility's activities, the extent of which cannot be predicted.

The Fund is reliant upon the Manager for the administration and management of all matters relating to the Facility.

Outlook

At this time, distributions to unitholders in the year 2001 are expected to be similar to the 2000 results of $0.94 per unit.

The Fund continues to seek acquisition opportunities that meet specified criteria in the trust indenture for increasing distributions while also protecting the Fund's current risk profile.

The Manager will seek unitholder approval for changes to the management agreement to facilitate the Fund's ability to participate in the competitive market. The Manager is proposing to bear the costs and risks associated with complying with the on-going technical and operational requirements of the new market rules (rather than the Fund) and to absorb any one-time costs in excess of $250,000 (up to which amount the Fund is responsible), in return for a share of any future benefits achieved by the Fund. The Manager continues to believe that participation in the competitive marketplace will offer the Fund and its unitholders significant opportunities and benefits.

Auditors' Report

To the Unitholders of Northland Power Income Fund

We have audited the consolidated balance sheets of Northland Power Income Fund as at December 31, 2000 and 1999, and the consolidated statements of income and deficit and cash flows for the years then ended. These financial statements are the responsibility of the Manager of the Fund. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Fund as at December 31, 2000 and 1999, and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP
Chartered Accountants

Toronto, Canada
March 2, 2001

Consolidated Balance Sheets

As at December 31, in thousands of dollars

Assets	2000	1999
Current		
Cash and cash equivalents	–	7,987
Restricted cash [note 1]	**211**	426
Accounts receivable [note 3]	**12,569**	6,406
Inventories [note 4]	**1,673**	882
Prepaid expenses	**576**	595
Total Current Assets	**15,029**	16,296
Deferred maintenance fee, net	**1,905**	2,997
Capital assets, net [note 5]	**239,425**	248,513
Future income tax asset [note 10]	**1,432**	–
	257,791	267,806

Liabilities and Unitholders' Equity	2000	1999
Current		
Bank indebtedness [note 6]	**2,105**	–
Accounts payable and accrued liabilities	**4,346**	3,470
Distribution payable to unitholders	**3,390**	7,706
Total Liabilities	**9,841**	11,176
Commitments and contingencies [notes 6 and 11]		
Unitholders' Equity [note 7]	**247,950**	256,630
	257,791	267,806

See accompanying notes.

Approved on behalf of Northland Power Income Fund
by Iroquois Falls Power Management Inc.

James C. Temerty
President

Consolidated Statements of Income and Deficit

Years ended December 31

In thousands of dollars, except per unit information

	2000	1999
Sales	**61,576**	59,850
Cost of sales	**25,584**	25,166
Gross Profit	**35,992**	34,684
Expenses		
Plant operating costs	**5,967**	5,762
Amortization	**9,240**	9,242
Management and administration costs [note 9]	**2,027**	1,473
Interest expense and bank fees	**135**	112
Interest income	**(259)**	(316)
	17,110	16,273
Income before income taxes	**18,882**	18,411
Provision for (recovery of) income taxes [note 10]		
Current	**20**	21
Future	**(103)**	–
	(83)	21
Net Income for the Year	**18,965**	18,390
Deficit, beginning of year	**(33,522)**	(23,246)
Adjustment for change in income tax accounting policy [note 2]	**1,329**	–
Distributions to unitholders [note 8]	**(28,974)**	(28,666)
Deficit, End of Year [note 7]	**(42,202)**	(33,522)
Net Income per Trust Unit [note 2]	**$0.62**	$0.60

See accompanying notes.

Consolidated Statements of Cash Flows

Years ended December 31, in thousands of dollars

Operating Activities	2000	1999
Net income for the year	**18,965**	18,390
Add items not involving cash:		
Amortization	**9,240**	9,242
Amortization of maintenance fee	**1,092**	1,092
Future income taxes	**(103)**	–
Funds from operations before changes in working capital	**29,194**	28,724
Net change in non-cash working capital balances related to operations	**(6,059)**	546
Cash Provided by Operating Activities	**23,135**	29,270
Investing Activities		
Purchase of capital assets	**(152)**	(82)
Cash Used in Investing Activities	**(152)**	(82)
Financing Activities		
Restricted cash drawdown	**215**	25
Increase in bank indebtedness	**2,105**	–
Distributions to unitholders	**(33,290)**	(28,666)
Cash Used in Financing Activities	**(30,970)**	(28,641)
Net Increase (Decrease) in Cash and Cash Equivalents During the Year	**(7,987)**	547
Cash and cash equivalents, beginning of year	**7,987**	7,440
Cash and Cash Equivalents, End of Year	**–**	7,987
Supplemental Cash Flow Information		
Interest paid	**23**	83
Income Taxes Paid	**20**	51

See accompanying notes.

Notes to Consolidated Financial Statements

December 31, 2000

1. Description of Business

Northland Power Income Fund (the "Fund") was established under the laws of the Province of Ontario pursuant to a Declaration of Trust. The Fund derives its distributable cash flow from Iroquois Falls Power Corp. ("IFPC"), a special-purpose corporation, wholly owned by the Fund. The Iroquois Falls cogeneration power facility (the "Facility") produces electricity for sale to Ontario Electricity Financial Corporation ("OEFC") under the provisions of a contract expiring in 2021 and steam for sale to Abitibi-Consolidated Inc. ("Abitibi") under the provisions of a contract expiring in 2016. Natural gas for the Facility is purchased under long-term contracts expiring in the years 2015 to 2017.

As part of the acquisition, restricted cash of $1,983,000 was acquired in order to complete the construction of the plant. At December 31, 2000, the restricted cash balance is $211,000 (1999 – $426,000). During the year, $215,000 of restricted cash was used to purchase capital assets (1999 – $25,000).

2. Summary of Significant Accounting Policies

These consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and within the framework of the significant accounting policies summarized as follows:

Principles of consolidation

These consolidated financial statements include the accounts of the Fund and the accounts of IFPC. All inter-entity transactions have been eliminated.

Cash and cash equivalents

Cash equivalents comprise only highly liquid investments with original maturities of less than ninety days and are recorded at cost, which approximates market value. The average interest rate on short-term investments held as at December 31, 2000 approximates 0% per annum (1999 – 4.5%).

Use of estimates

The preparation of consolidated financial statements in conformity with GAAP requires that Iroquois Falls Power Management Inc. (the "Manager"), the administrator of the Fund and the manager of the Facility, make estimates and assumptions about future events that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the dates of the consolidated financial statements, and revenue and expenses during the reporting period. Actual results could differ from those estimates.

Inventories

Inventories comprise natural gas, spare parts and other inventory. Natural gas is carried at the lower of cost, as determined on a weighted average basis, and net realizable value. Spare parts and other inventory are carried at the lower of cost and net replacement cost.

Capital assets

Capital assets are recorded at cost less accumulated amortization. Amortization is provided on a straight-line basis at rates designed to amortize the cost of the assets over their estimated useful lives as follows:

Buildings and foundations	30 years
Plant and equipment	30 years
Contracts [note 3]	over the term of the agreements
Vehicles	5 years
Office equipment, furniture and fixtures	5 years
Computers and computer software	2 years

Deferred maintenance fee

The deferred maintenance fee is amortized over the original term of an agreement between IFPC and General Electric Canada Inc. for the maintenance of the gas turbines. This agreement expires in 2008 and is renewable upon expiry.

Revenue recognition

Revenue for electricity and gas is recognized upon delivery. Revenue for steam is recognized as earned.

Net income per trust unit

Net income per trust unit is based on the consolidated net income for the year over the weighted average number of trust units outstanding during the year, which was 30,823,443 (1999 – 30,823,443).

Income taxes

Effective January 1, 2000, the Fund and IFPC adopted the liability method of tax allocation for accounting for income taxes as provided for in the new recommendations of the Canadian Institute of Chartered Accountants ("CICA"), section 3465. Under the liability method of tax allocation, future tax assets and liabilities are determined based on differences between the financial reporting and tax bases of assets and liabilities and are measured using the substantially enacted tax rates and laws that will be in effect when the differences are expected to reverse.

Under the terms of the Income Tax Act (Canada), the Fund is not subject to income taxes to the extent that its taxable income in a year is paid or payable to a unitholder. Accordingly, no provision for current income taxes for the Fund is made. In addition, as the Fund is contractually committed to distribute to its unitholders all or virtually all of its taxable income and taxable capital gains that would otherwise be taxable in the Fund, the Fund intends to continue to meet the requirements under the Income Tax Act applicable to such trusts, and there is no indication that the Fund will fail to meet those requirements, the Fund is not subject to the recommendations of the CICA section 3465.

The Fund's wholly owned subsidiary, IFPC, is subject to corporate income taxes as computed under the Income Tax Act and CICA section 3465.

The adoption of the liability method has been applied retroactively as at January 1, 2000, without restatement of the prior year consolidated financial statements. The cumulative effect of the adoption of the liability method as at January 1, 2000, was to increase future tax assets and decrease the deficit by $1,329,000.

For reporting periods which ended before January 1, 2000, income tax expense was determined using the deferral method of tax allocation. Under this method, future tax expense was based on items of income and expense that were reported in different years in the financial statements and tax returns and measured at the rate in effect in the year the difference originated.

Employee future benefits

Effective January 1, 2000, the Fund adopted the recommendations of the CICA section 3461, Employee Future Benefits. The new standard requires the recognition, on an accrual basis, of the cost of all benefits that will be paid to or on behalf of employees. The impact of this recommendation in the current period is minimal.

3. Economic Dependence and Concentration of Credit Risk

The Fund is entirely dependent on the facility lease income, interest income and dividends received from IFPC. In 2000, approximately 82% (1999 – 84%) of IFPC's revenue was derived from the sale of electricity to OEFC. Approximately 7% (1999 – 7%) of IFPC's revenue was derived from the sale of steam to Abitibi.

Approximately 84% (1999 – 86%) of the year-end accounts receivable balance was due from OEFC relating to electricity sales. Approximately, 5.4% (1999 – 14%) of the year-end accounts receivable balance was due from Abitibi relating to steam sales.

4. Inventories – In thousands of dollars

Inventories consist of the following:	2000	1999
Natural gas	**732**	39
Spare parts and other inventory	**941**	843
	1,673	882

5. Capital Assets – In thousands of dollars

Capital assets consist of the following:	2000		1999	
	Cost	**Accumulated amortization**	Cost	Accumulated amortization
Land	**126**	**–**	126	–
Buildings and foundations	**23,159**	**2,892**	23,159	2,120
Plant and equipment	**236,950**	**29,585**	236,817	21,694
Contracts	**13,668**	**2,050**	13,668	1,503
Vehicles	**26**	**9**	11	6
Office equipment, furniture and fixtures	**57**	**32**	55	20
Computers and computer software	**91**	**84**	89	69
	274,077	**34,652**	273,925	25,412
Net book value		**239,425**		248,513

6. Credit Agreement

The Fund has a credit agreement with the Canadian Imperial Bank of Commerce that is subject to renewal on the anniversary date of April 16, 2001, which establishes a $7,500,000 revolving-term letter of credit facility to be used in meeting obligations under gas transportation and supply contracts and a $5,000,000 revolving-term operating line of credit for general corporate purposes. Interest per annum under the operating line of credit agreement is charged at the bank's prime rate plus 2.0% (9.25% at December 31, 2000). There is also a fee of 1.3% per annum charged on the outstanding amount of the letter of credit. Standby fees of 0.5% are charged on each of the undrawn letter of credit and operating line facilities.

At December 31, 2000, a letter of credit for $5,920,000 (1999 – $5,920,000) was outstanding under the letter of credit facility. At December 31, 2000, $2,105,000 (1999 – nil) has been drawn on the operating line.

Amounts drawn under the credit agreement are principally collateralized by a debenture security and by general security agreements which constitute a first priority lien on all of the real property and all of the present and future property assets of IFPC and the Fund, as well as a pledge by the Fund of its current and future interests in the capital stock of IFPC, notes payable and all other securities issued by IFPC to the Fund.

7. Unitholders' Equity

The Trustee may issue an unlimited number of trust units subject to rules governing the trust indenture. Each trust unit represents an equal fractional beneficial interest in the Fund. All trust units are transferable and share equally in all distributions from the Fund whether of net income, return of capital, return of principal, interest, dividends or net realized capital gains or other amounts, and in the net assets of the Fund in the event of termination or winding-up of the Fund.

	2000	1999
Issued and outstanding		
30,823,443 trust units	**290,152**	290,152
Deficit	**(42,202)**	(33,522)
	247,950	256,630

The trust units are redeemable at any time on demand by the holders at their fair value, determined as the lesser of: (a) 95% of the "market price" of the trust units on the principal market on which the trust units are quoted for trading during the 10-trading-day period commencing immediately after the date on which the trust units are surrendered for redemption; and, (b) the "closing market price" on the principal market on which the trust units are quoted for trading on the date that the trust units are surrendered for redemption.

The aggregate redemption price payable by the Fund in respect of any trust units surrendered for redemption during any calendar month shall be satisfied by way of a cash payment on the last day of the following month; provided that the entitlement of unitholders to receive cash upon redemption of their trust units is subject to the limitations that: (a) the total amount payable by the Fund in respect of such trust units and all other trust units tendered for redemption in the same calendar month shall not exceed $200,000, (b) at the time such trust units are tendered for redemption the outstanding trust units of the Fund shall be listed for trading on a stock exchange or traded or quoted on any other market that IFPC's Directors consider, in their sole discretion, provides representative fair market value prices for the trust units, or (c) the normal trading of trust units is not suspended or halted on any stock exchange on which the trust units are listed on the date that the trust units are tendered for redemption or for more than five trading days during the 10-trading-day trading period commencing immediately after the date on which the trust units are tendered for redemption.

8. Distributions to Unitholders

Cash provided by operating activities for the year ended December 31, 2000, was $0.75 per trust unit (1999 – $0.95 per trust unit), being an aggregate amount of $23,135,000 (1999 – $29,270,000).

Distributions totaling $0.94 per trust unit (1999 – $0.93), being aggregate distributions of $28,974,000 (1999 – $28,666,000), were determined by the Manager of the Fund for the year ended December 31, 2000. For income tax purposes, $28,510,000 (1999 – $28,007,000) of the distributions is a return of capital.

9. Management Fee

Iroquois Falls Power Management Inc. is entitled to receive a fee from the Fund and IFPC for services provided related to the operation, management and administration of the Facility pursuant to a 25-year management agreement expiring in 2021. The fee is payable on a monthly basis at a rate of 1/12 of $460,000, adjusted annually with changes to the Consumer Price Index. During the year ended December 31, 2000, the Manager was paid $478,000 (1999 – $469,000).

The Manager is also entitled to receive a management incentive fee equal to 25% of the amount by which annual distributions to the unitholders exceed $0.934 per trust unit. The Manager is also entitled to other operation-related incentive fees. During the year ended December 31, 2000, the Manager earned $397,000 (1999 – $75,000) as an operation-related incentive fee.

10. Income and Other Taxes

In thousands of dollars	2000	1999
Method	**Liability**	Deferral
The components of the income tax expense (recovery) are as follows:		
Current		
Federal	**20**	21
Provincial	–	–
Future		
Federal	**(66)**	–
Provincial	**(37)**	–
Provision for (recovery of) income taxes	**(83)**	21
The components of future income tax liabilities and assets are as follows:		
Future Tax Liabilities		
CCA in excess of book depreciation	**161**	–
Total future tax liabilities	**161**	–
Future Tax Assets		
Loss carryforwards	**1,593**	–
Total future tax assets	**1,593**	–
Net Future Tax Assets	**1,432**	–
Income before income taxes	**18,882**	18,411
Combined federal and provincial income tax at statutory rate of 43.95% (1999 – 44.62%)	**8,299**	8,215
Manufacturing and processing deduction	**(604)**	(206)
Income of Fund distributed to unitholders	**(7,906)**	(8,532)
Effect of tax losses not recorded	–	523
Future income tax expense resulting from rate change	**108**	–
Large Corporations Tax and other items	**20**	21
Provision for (Recovery of) Income Taxes	**(83)**	21

At December 31, 2000, financing expenses and underwriters' fees of $4,082,000 (1999 – $7,699,000) are deductible by the Fund for income tax purposes on a straight-line basis over the next two years.

At December 31, 2000, IFPC has non-capital losses available for carryforward of approximately $4,619,000 which are available to reduce future year taxable income. These losses expire from 2003 to 2007.

11. Commitments

In the ordinary course of business, IFPC has entered into agreements to ensure an adequate supply of natural gas and transportation thereof to the Facility, expiring in the years 2015 to 2017.

Historical Review

Years ending December 31

In thousands of dollars, except as specified

	2000	1999	1998	1997*
Financial				
Electricity production (MWh)	**739,687**	778,307	732,034	517,058
Steam production (000 lbs.)	**997,164**	868,431	779,609	769,833
Sales				
Electricity	**$50,570**	$51,704	$49,588	$34,063
Steam	**4,504**	4,381	3,713	3,067
Gas	**6,502**	3,765	2,128	1,561
	61,576	59,850	55,429	38,691
Cost of Sales	**25,584**	25,166	22,048	15,090
Gross Profit	**35,992**	34,684	33,381	23,601
Expenses				
Plant operating costs	**5,967**	5,762	5,890	4,076
Amortization	**9,240**	9,242	9,250	6,922
Management, administration costs	**2,027**	1,473	1,337	924
Installment loan interest expense and bank fees	**135**	112	1,996	4,629
Interest income	**(259)**	(316)	(371)	(209)
	17,110	16,273	18,102	16,342
Provision for (Recovery of) Income Taxes				
Current	**20**	21	67	98
Future	**(103)**	–	(85)	85
	(83)	21	(18)	183
Net Income	**$18,965**	$18,390	$15,297	$7,076
Funds from Operations, Before Working Capital Changes	**$29,194**	$28,724	$27,420	$19,531
per unit	**$0.95**	$0.93	$0.89	$0.63
Cash from Operations	**$23,135**	$29,270	$27,421	$17,973
per unit	**$0.75**	$0.95	$0.89	$0.58
Distributions to Unitholders	**$28,974**	$28,666	$27,125	$18,494
per unit	**$0.94**	$0.93	$0.88	$0.60

* Nine months

Corporate and Unitholder Information

Principal Office
c/o Iroquois Falls Power Management Inc.
30 St. Clair Avenue West
17th Floor
Toronto, Ontario M4V 3A2

Trustee
Montreal Trust Company of Canada
100 University Avenue
Toronto, Ontario M5J 2Y1
Attention: Corporate Services

Directors & Officers of Iroquois Falls Power Corp.

James C. Temerty
President
President, Iroquois Falls Power Management Inc. and Northland Power Inc.

Anthony F. Anderson
Chief Financial Officer
Chief Financial Officer, Iroquois Falls Power Management Inc. and Northland Power Inc.

Pierre R. Gloutney*
Director
President and Chief Executive Officer
Refco Futures (Canada) Ltd.

A. Warren Moysey*
Director
Director and Vice-Chairman, CGU Canada Ltd.

The Right Honourable John N. Turner, Q.C.
Director
Partner, Miller Thomson LLP

F. David Rounthwaite*
Director
Partner, McCarthy Tétrault LLP

Linda L. Bertoldi
Secretary
Partner, Borden Ladner Gervais LLP

Legal Counsel
Borden Ladner Gervais LLP
Toronto, Ontario

Auditors
Ernst & Young LLP
Toronto, Ontario

Bank
Canadian Imperial Bank of Commerce
Commerce Court West
Toronto, Ontario

Registrar & Transfer Agent
Computershare Trust Company of Canada
100 University Avenue
Toronto, Ontario M5J 2Y1
Attention: Equity Services

Trust Units
The trust units are listed on The Toronto Stock Exchange and trade under the symbol NPI.UN.

Annual Meeting Date and Place
The fourth annual meeting of unitholders of Northland Power Income Fund will be held on *Thursday, May 24th, 2001, at 11:00 a.m.* in the TSE Conference Centre, located at The Exchange Tower, 130 King Street West (corner of King & York Streets), Toronto, Ontario.

For investor information, please contact:
Barbara Bokla
Iroquois Falls Power Management Inc.
30 St. Clair Avenue West
17th Floor
Toronto, Ontario M4V 3A2

Telephone: 416-962-6262, Extension 156
Facsimile: 416-962-6266
E-mail: info@NPIFund.com
Web site: NPIFund.com

* Member of the Audit Committee

Governance, The Board, Distribution and Funding Policy

Governance: The Roles of the Trustee, the IFPC Board and the Manager

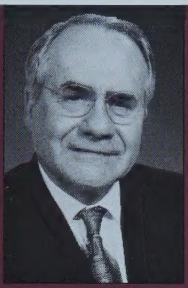
As Trustee, Montreal Trust Company of Canada has responsibility for the administration of the Fund. The Trustee has delegated administrative responsibility for the Fund to Iroquois Falls Power Management Inc. (the "Manager") under an administration agreement.

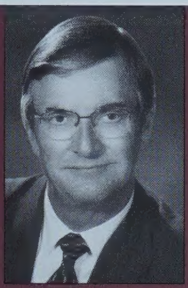
The Board of Directors of IFPC has responsibility for the management of the Facility, the administration of the contracts, and the operation of the business of selling electricity and steam. In addition, the Board reviews the operations of the Fund and provides advice to the Manager. The Board consists of five directors, four of whom are independent of the Manager. The Board has delegated the day-to-day management responsibilities to the Manager under a management agreement expiring in 2021.

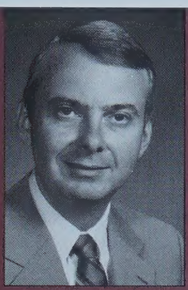

James C. Temerty


Anthony F. Anderson


Linda L. Bertoldi


Pierre R. Gloutney


A. Warren Moysey

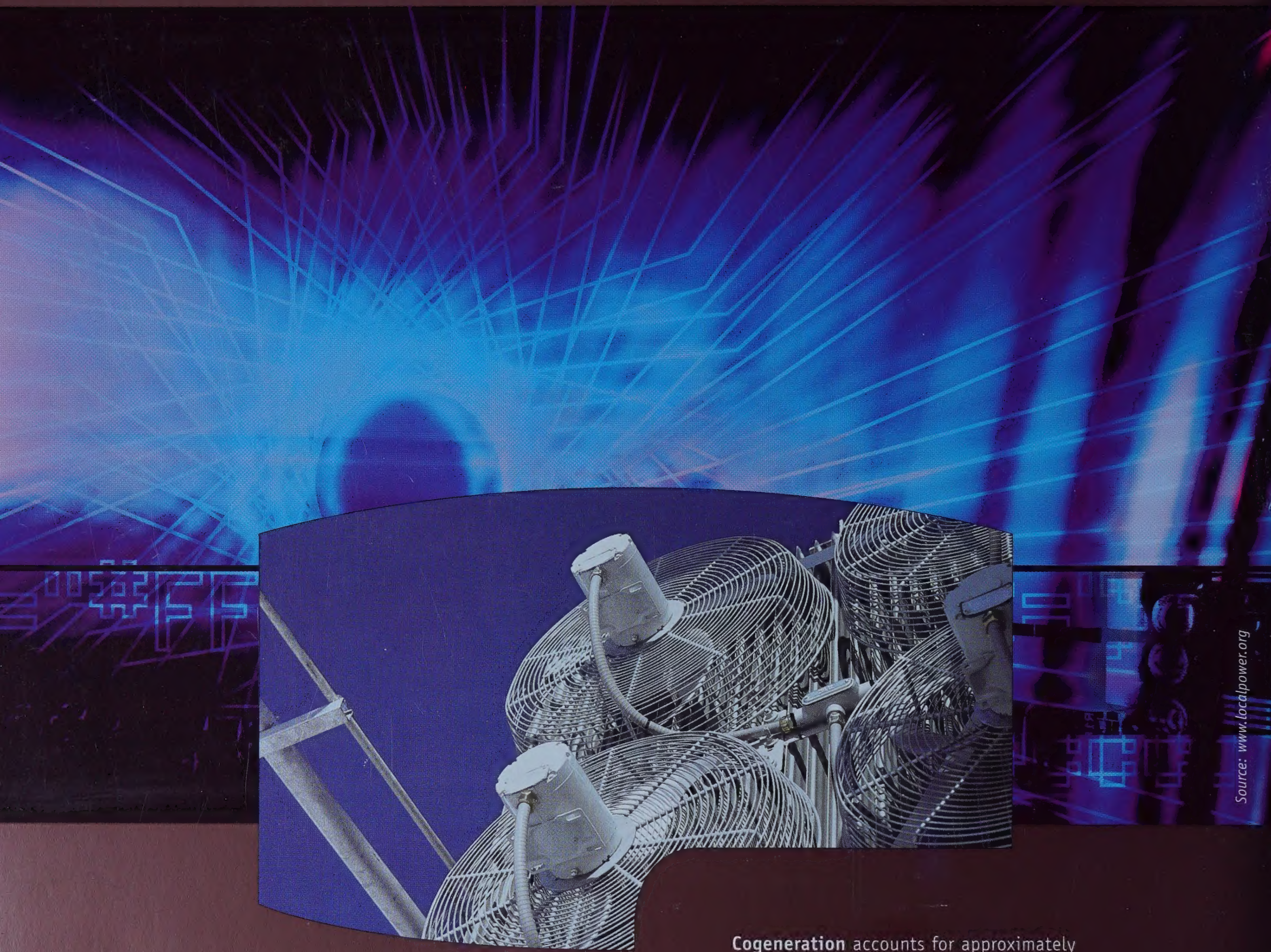

F. David Rounthwaite


The Right Honourable John N. Turner, Q.C.

Directors & Officers of Iroquois Falls Power Corp.

Distribution and Funding Policy

It is the Fund's policy to distribute 100 per cent of cash flow to unitholders after providing for required capital expenditures and any increases in working capital, which are not expected to be material. It is anticipated that material capital expenditures that enhance cash flow and distributions to unitholders will be financed using the operating line of credit which will then be repaid from incremental cash flow; permitted acquisitions and plant expansions, if any are undertaken, would be funded by a combination of borrowings and the issuance of additional trust units.



Source: www.localpower.org

Cogeneration accounts for approximately 7 per cent of the world's power production, and more than 40 per cent in some European countries. Targets set in the United States and EU aim to double the share of cogeneration by 2010.

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